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Demand response in smart electricity grids equipped with renewable energy sources: A review

Jamshid Aghaei *, Mohammad-Iman Alizadeh

Department of Electrical and Electronics Engineering, Shiraz University of Technology, Shiraz, Iran

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ABSTRACT

Dealing with Renewable Energy Resources (RERs) requires sophisticated planning and operation scheduling along with state of art technologies. Among many possible ways for handling RERs, Demand Response (DR) is investigated in the current review. Because of every other year modifications in DR definition and classification announced by Federal Energy Regulatory Commission (FERC), the latest DR definition and classification are scrutinized in the present work. Moreover, a complete benefit and cost assessment of DR is added in the paper. Measurement and evolution methods along with the effects of DR in electricity prices are discussed. Next comes DR literature review of the recent papers majorly published after 2008. Eventually, successful DR implementations, around the world, are analyzed.

Contents

1. Introduction

Today, environmental concerns, oil crisis, and economic aspects of utilizing the available energy resources efficiently motivated nations, governments, technology providers, and academic societies to substitute conventional resources by Renewable Energy Resources (RESs) [1,2]. Hence, many attempts are in process over integrating renewable resources with macro grids. Power systems, however, have some inherent characteristics, which are needed to be scrutinized. Firstly, electricity supply must always equal demand because of frequency balance. Secondly, electric power is not economically storable at the scale of large power systems. Variations in power consumption come next due to consumer behavior. Finally, power

* Correspondence to: Department of Electrical and Electronic Engineering, Shiraz University of Technology, Modares Blvd. Shiraz, P.O.71555-313, Iran. Tel.: +98 711 7264121; fax: +98 711 7353502.
E-mail address: aghaei@sutech.ac.ir (J. Aghaei).

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generation costs may vary remarkably because of generation unit classifications [3]. For many reasons, in a conventional power system consumers are exposed to fixed annual rates without seeing the whole market conditions. The Independent System Operator (ISO), in a deregulated power system, has the authority to deal with the mentioned variations in electricity costs and volatilities in power consumption in order to operate the power system in safe and secure conditions [4]. One of the most important features of a deregulated power system is to avoid large-scale power plants and to decentralize generation into local generation units called Distributed Energy Resources (DERs) [5]. Nowadays, DERs are widely used to counteract the above-mentioned issues regarding power systems. An efficient approach to implement DERs practically along with High-Tech communication and control devices is called Micro Grid (MG), which can cause significant improvements in deregulated power system operating conditions. MG, in its general prospective, is an exemplar of a macro grid. In a MG, local energy potentials are mutually cooperated with each other and upstream network as well [6]. DGs in both forms of RESs and nonconventional thermal units such as Micro Turbines (MTs), and Diesel engine Generators (Dgen) are exploited extensively in a MG. RES Penetration to power systems as dispatchable generation units is accompanied by some difficulties such as uncertainties associated with wind and solar power generations. These uncertainties pose a challenge while computing optimal bids necessary for participating in the day-ahead unit commitment process. Some authors solved this problem by applying fuzzy optimization techniques, with the aim of both maximizing benefits while minimizing risks considering forecast uncertainties [47]. To overcome the intermittency of wind, solar power generation, and mentioned power market issues intelligent and automated control systems along with Demand Response Programs (DRPs) and storage devices in a micro grid scale are required [7]. Moreover, the following solutions are presented in [46]:

Power plants providing operational and capacity reserve.

- Interconnection with other grid systems.
- Curtailment of intermittent technology.
- Dispatchable distributed generation.
- Use of complementarity between renewable sources.
- Demand-side management.

The first assessment of DR and Advanced Metering (AM) was released in 2006 and the modified version was published in 2008 consecutively. Significant changes in classifications, however, took place from twelve in 2008 to fifteen in 2010. These noticeable modifications in DR area between 2008 and 2010 motivated authors to review recent contributions and modifications presented in literatures and to extend [8] as the main framework of the present review.

2. Demand response definition

In the strategic plan of International Energy Agency (IEA) for 2008–2012, demand side activities have been in warmth of spot light in all energy policy decisions because of their significant benefits both at economic and operational levels [9]. A comprehensive definition for DSM can be stated as what was expressed in [14]. The DMS optimizes the power flows in the network, regulates the voltage profiles, acting on reactive flows and tap changers in substation, minimizes the energy losses, reconfigures the network, exploits storage devices and responsive loads in an integrated way. Considering overall purpose of the Load management (LM) programs, three types of Demand Side Management (DSM) are definable [9,10]:

(1) Economic/Market-driven: The purpose of this program is to reduce general costs of energy supply, increase the reserve margin, and mitigate price volatility by means of smart-term responses to electricity market conditions.
(2) Environmental-driven: Provides environmental and/or social purposes by decreasing energy usage, defining commitment of not environmentally friendly generation units, leading to energy efficiency augmentation, and/or reduction in greenhouse gas emissions.
(3) Network-driven: The aim of this program is maintaining the system reliability by decreasing demand in a short period of time and reducing extra generation/transmission capacity enhancement.

In addition to the above classifications, a more precise definition of DRP seems to be crucial. One of the basic comprehensive DR definitions, as a subsequent part of DSM programs, announced by FERC says that DR is the ability of customers to respond to either a reliability trigger or a price trigger from their utility system operator, load-serving entity, regional transmission organization (RTO)/ISO, or the demand response provider by lowering their power consumption [11]. For many years, according to the term, DR means just peak clipping approach for specific hours of a year. Order no. 719, however, defined DR to mean a reduction in consumption of electric energy by customers from their normal consumption pattern in response to a price augmentation or incentive payment designed to encourage lower consumption of electric energy [11]. As what can be inferred from the recent definition, DR includes incentive payment actions in addition to peak clipping actions. Meanwhile, Nordic Power Market (NORDEL) defined DR in a similar frame but with modified details. The NORDEL uses DR to refer to a voluntary temporary adjustment of electricity demand in response to a price signal or a reliability-based action.

- DR can be implemented in a short period of time (Capacity) or medium-term (Energy).
- The price signals can be sent from the power market, intraday market, and regulatory power market after a Transmission System (TSO) Call, balancing markets or from tariffs.
- TSO along with distribution companies have the authority to provide reliability-based actions, which can be activated manually or automatically.
- DGs can be considered as a DR from consumption prospective [3].

Responsive demand, however, refers to those changes applied by customers to their expected load pattern in response to energy price signals for improving the economic efficiency of their energy. The mechanism discourages the energy load when real-time price is high and vice versa. Consequently, peak reduction and eco-friendly standard of life is obtained by performing this mechanism [12,13] Eventually, the recent definition of DR used in [24] and report is:

Demand Response: Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

This definition substitutes “demand-side resources” for the phrase “end-use customers” used in previous surveys, to conform to the definition in use by NERC’s Demand Response Data Task Force in its development of a Demand Response Availability Data System (DADS) to collect demand response program information [24].

3. Requirements

FERC staff recently modified definition for advanced meters to be consistent with that used by the Energy Information Administration

(EIM). The report says Advanced Meters are Meters that provide usage data, measured and recorded at hourly intervals or more frequently, to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters, one-way communication meters, and real-time meters with built-in two-way communication cable of recording and transmitting instantaneous data.

The modified definition resulted in changes in advanced meter counts by some entities responding to the 2010 Survey compared to the 2008 and 2006 FERC Surveys. In follow-up calls, staff learned that three respondents reclassified meters previously reported as advanced meters to non-advanced meters because of the new requirement of "providing customers with usage data at least once daily." [24].

An efficient infrastructure to implement a DRP practically is Energy Management System (EMS) in a Smart Grid (SG) infrastructure. The term SG is a fully automated electric power system which has the authority to control and optimize the operation of all its interconnected elements, in order to operate generation, transmission, and distribution safely and efficiently [16,17]. Today, many countries exercise SGs, including, for example, U.S., Canada, Germany, Japan, India, and Australia [18,19]. Further initiatives towards the future SGs are concerned with the so called Virtual Power Plants (VPPs) which means aggregating interconnect DGs placed in different locations by managing them to work as a unique power plant. This method allows even the smallest DG to participate in electric market and contribute to energy cost reduction process [20]. In [21] a VPP with combined heat and power micro-units is presented. VPP cooperated with DR and wind power generation is also investigated in [22]. A possible scenario to achieve a dynamic control of all interconnected elements is as follows:

- supervisory control and data acquisition (SCADA);
- remote terminal units (RTUs);
- advanced metering infrastructure (AMI);
- state estimation algorithms (SEAs);
- generation and load forecast system (GLFS).

In the context of DR, there is a need to develop a consistent approach for integrating the communication backbone for providing price signals or notification of system emergencies with the Advanced Metering Infrastructure (AMI) system. Advanced metering systems (AMS) are comprised of state-of-the-art electronic/digital hardware and software, which combine interval data measurement with continuously available remote communications. These systems enable measurement of detailed, time-based information and frequent collection and transmittal of such information to various parties. AMI typically refers to the full measurement and collection system that includes meters at the customer site, communication networks between the customer and a service provider and data reception and management systems that make the information available to the service provider [15]. The SCADA system transmits the measurement data, provided by an AMI and a set of remote collecting data devices (RTUs) placed in strategic positions along the SG, to the EMS. The latter determines the actions required for the optimum state of the SG by using SEAs and GLFS [23].

It is using new communication technology innovations and policy directions that many DR actions can change any part of the load profile of a utility or region, not just the period of peak usage.

4. Customer categorization and characterization

Electricity customers can be classified into the three main parts namely, industrial, commercial, and residential customers. All of the above mentioned customers have their own specific characteristics to be participated in DRPs. Customers can participate in DRPs by decreasing their usage during critical peak periods when prices are high without changing their consumption pattern as illustrated in Fig. 1. Another alternative can be a reduction in customer's normal consumption pattern by shifting some of their peak demand usage to off-peak hours as shown in Fig. 2.

The last choice for customers is employing DGs to supply their demand in high price hours. As reported in [24] commercial and industrial customers, though fewer in number than residential customers, provide a higher total level of load reduction potential than residential customers. Because of the available systems and technology in place commercial and industrial customers are more likely to facilitate demand response program participation. Moreover, many demand response programs are available only to customers above a certain size cut-off. As it can be inferred from Fig. 3, potential peak load reduction rose rapidly from just below 15,000 MW in 2006 to far more than 20,000 MW in 2010 for commercial and industrial customers.

In contrast, potential peak load reduction for residential customers showed a slight upward trend from about 6000 MW in 2006 to near 7500 MW in 2010 respectively. This means that commercial and industrial customers, though fewer in number

Fig. 1. Curtailing load without changing load pattern.

Fig. 2. Load shifting.

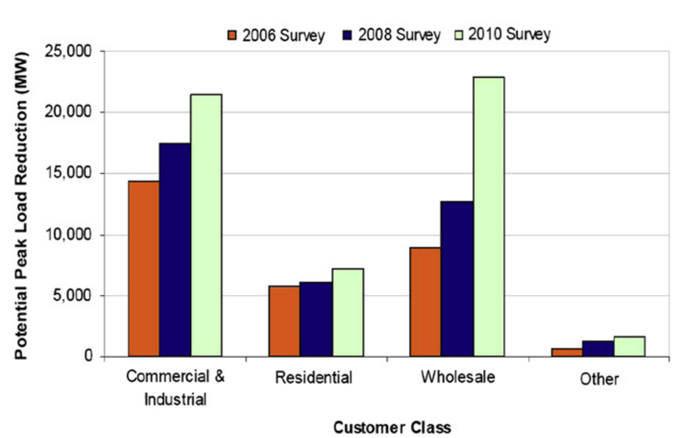

Fig. 3. Potential peak load reduction.

than residential customers, provide a higher total level of load reduction potential than residential customers.

5. DRPs classification

DRPs classification has been changed a lot since 2006, when the first Assessment of Demand Response and Advanced Metering was announced by FERC. Previously, DRPs had been classified into two major categories namely, Incentive-based programs (IBP) and Price-based programs (PBP). Ref. [24], however, presented all programs without previous clustering. It is worth noting that the number of the programs, specified by FERC Surveys, was twelve in 2008 and fifteen in 2010 respectively. This part is dedicated to the recent program categorizations and definitions.

Direct Load Control as one of the most efficient and popular DRPs is defined as an activity by which the sponsor (i.e. RTO, ISO, or local provider) turns off or cycles a customer's electrical equipment (e.g. air conditioner, water heater) remotely on short notice. This program is basically offered to low consumption customers (i.e. residential and small commercial customers). Interruptible Load Program has the responsibility to curtail or interrupt an electric consumption under tariffs or contracts that provide a rate discount or bill credit for agreeing to regulate load in case of system contingencies. In some cases, System Operator might reduce load after noticing customer in accordance with contractual provisions. One of the recently added programs is Critical Peak Pricing with Control, which is a combination of direct load control programs and a pre-specified high price during allocated critical peak hours, triggered by system contingencies or high wholesale market price. Load as a Capacity Resource, the latest terminology of Capacity program, is a Demand Side Resource (DSR) that commits to reduce the pre-specified amount of load in case of contingencies. Spinning reserve (responsive reserve), previously included in ancillary services, is a DRP that is synchronized and always prepared to deal with any demand and supply imbalance as a cure within the few minutes when an emergency event occurs. Non-spinning reserve, previously counted as an ancillary service, can be activated with a ten minutes delay to solve energy supply and demand imbalance. Emergency DRP is a DSR that encourages customers to reduce their loads during emergency DR events by offering incentive payments. Regulation Service, prior to the latest FERC Survey counted as one of the ancillary service, is a DR service by which an SO can increase or decrease a customer's load in response to real time signals. This DRP is preformed continuously during a commitment period. Providing normal regulating margin is the main responsibility of the service as an Automatic Generation Control (AGC) provider. Some literature papers named this service as regulation or regulating reserves, up-regulation, and down-regulation. Demand Bidding and Buy-back as a DRP gives the authority to a demand resource to offer load reductions associated with a price or to specify how much load can be curtailed at a given price. This service can be employed in both retail and wholesale market. Time of Use (TOU) is a service, which provides different electricity prices associated with different periods. It is worth noting that the rates specified by this service reflect the average cost of power generation and delivery during each time intervals, which are typically longer than one hour within a 24-hour day. Critical Peak Pricing program allocates high electricity prices/rates during restricted number of days or hours in case of high wholesale market prices or contingencies to discourage electricity consumption during mentioned time intervals. The Real Time Pricing (RTP) reflects the changes in wholesale price of electricity by fluctuating hourly or more often retail prices/rates. Economists believe that RTP programs are the most efficient and direct DR programs for being spotted in competitive markets [37]. Peak Time Rebate (extreme day pricing) is a service by which customers can earn a rebate by consuming electric energy less than a baseline during a determined number of hours on critical peak days which is typically capped for a calendar year because of reliability concerns over very high supply prices. Eventually, a System Peak Response Transmission Tariff, newly added program, functions during peak periods to specify terms, conditions, and rates and/or prices for customers with interval meters that decrease load as a way of abating transmission changes.

6. Benefits and costs

DR benefits as shown in Fig. 4 are assessed in seven categories in this paper:

Economic, pricing, risk management and reliability, market efficiency impacts, lower cost electric system and service, customer services, and environmental benefits.

Economic benefits can be classified among the most important DR advantages. From customers' point of view, acceptable rebates can be achieved in electricity bills if customers abate their consumption pattern as stated in contractual provisions [25–29]. Moreover, customers can obtain rebates even without reducing their total usage by shifting their consumptions from peak hours with high prices to off-peak hours. Savings are available for those customers who consume less than their class average during peak hours. Successful DR implementations revealed the acceptable effects of DR in electricity price reduction [24,30,31]. Implementing DRPs, in long term horizon, can cause wholesale market price abatements because of a more sophisticated utilization of available infrastructures, as in, for example a reduction of demand means a reduction in committing expensive generation units [8,29,32]. Besides, performing DRPs can increase short-term capacity costs. Consequently, avoided or deferred capacity costs such as need for distribution and transmission infrastructure upgrades are obtainable [8]. One of the other advantages of DR in pricing area is price volatility and hedging cost reduction.

Price volatility is explicitly shown in Fig. 5, at the spot market and consumption in Eastern Denmark, for two Mondays in

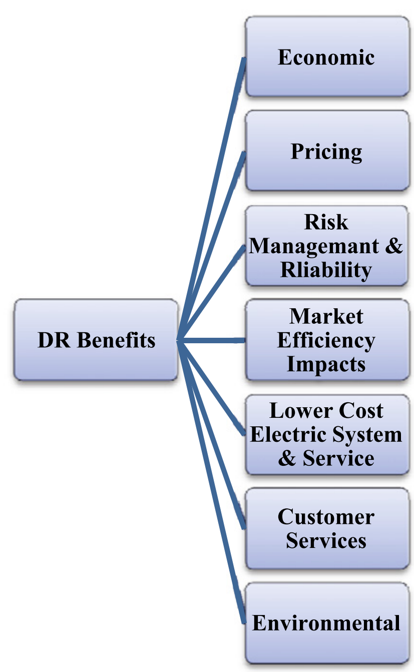

Fig. 4. DR benefits.

Fig. 5. DR costs.

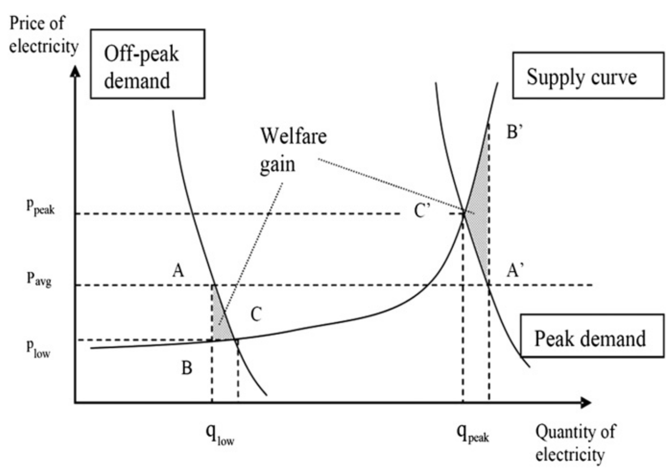

Fig. 6. Price volatility reduction with DRPs.

November 2005. On November 28 the price reached up to an extreme peak of DKK13, 469/MW, about 60 times more than the normal price level, but compared to a week before, consumption was almost unchanged. Demand responsiveness causes a large reduction in price volatility by displacing demand curve from peak demand to off-peak demand. As illustratively shown in Fig. 6, displacing demand curve caused a smaller deviation from the cost points B and B' to the points of intersection C and C'.

DRPs have also remarkable influences on risk reduction and reliability enhancement. Reliability advantages can be extracted from Ancillary Service DRPs (AS-DRPs). The basic concept of demand providing AS-DRPs is similar to that of a generator, except that rather than changing the level of generation output to the grid, the demand resource is changing its level of consumption from the grid. The Notice of proposed rulemaking (NOPR) identifies three ancillary services (regulation and frequency response, operating reserves—spinning, and operating reserves—supplemental) that might conceivably be provided by loads. Although it sounds that individual demand resources may have a high failure rate to curtail load on short notice, the aggregation of several smaller resources into one larger resource makes it probabilistic that the assigned response will be achieved. This characteristic of demand resources potentially makes demand response resources more reliable than conventional generation resources. For generating resources that are called upon and therefore produce energy for a period of up to 30 min, the resource is guaranteed recovery of its costs to provide the energy, including incremental and startup costs. Demand resources would similarly be reimbursed for any costs incurred during a spinning event. As a regulation provider, demand response can respond quicker to a regulation signal than a conventional, fossil fueled, steam generator could. Besides, DRPs have additional advantages on market power mitigation based on the concept that greater demand response and increased transparency will make it easier for individual players to monitor and respond to each other's behavior. Considering DRPs effects on electric system cost, many benefits are obtainable such as reducing peaking capacity requirements, decreasing transmission capital and operating expense, deducting distribution capital and operating expense, reducing in Load Serving Entities (LSE) commodity costs, and reducing in long-term resource adequacy requirements. Customers' choices in receiving electric power in proportion to their preferences have been increased by introducing DRPs. Eventually, FERC emphasizes on demand side resources instead of customers motivates penetrating Renewable Energy Resources (RERs) more and more in SGs. Consequently, lower released emission is obtainable.

7. DR Costs

Implementing and operating DRPs impose expenses to both demand side participants and service operators. Demand side participants have to buy and install smart thermostats, communication infrastructures, peak load control, and Energy Management Systems (EMSs). In addition to the capital costs, operating and maintenance costs have to be paid by participants as continuous expenses. Investments in Renewable Energy Resources (RERs) in demand side can be considered as participant costs. System operators or any other DRP provider such as Transmission System Operator (TSO) (e.g. NORDEL power system) or ISO are imposed some costs. These costs are communication infrastructures in control side and AMIs, which are responsible for measuring, gathering, storing, and transmitting energy consumption/supply information and can be considered as initial costs imposed to DR providers. Eventually, an important cost component before deploying DRP is educating eligible customers about DRP advantages.

8. Literature review

One of the most recent challenging issues regarding RERs (i.e. wind power generation, photovoltaic resources, solar systems) is that highly profitable resources are inherently intermittent and cannot be employed as dispatchable resources. Many attempts have been recently done to mitigate the intermittency behavior of RERs. Energy Storage Systems (ESSs) and DRPs are two major applicable solutions presented in recent papers. In [7] many recent problem formulations in case of integrating wind power generation and price responsive demand are compared with respect to information exchange requirements, computational complexity, and physically implementable dynamic model-predictive dispatch. Authors proposed a novel multi-directional interactive dynamic monitoring and decision-making systems (DYMONDS) algorithm to implement near-optimal predictive dispatch, instead of commonly used

Security-Constrained Economic Dispatch (SCED). To provide the input data, the proposed method requires information exchange in the function spaces, instead of only communicating (quantity, price) data points. They claim that mitigating the intermittency of RERs can be achieved by implementing (1) demand response, (2) predictive wind power model, and (3) the use of physically implementable dynamic model-predictive dispatch of responsive demand, wind power, and conventional power plants. Same authors in [33] showed, in a case study that the look-ahead dispatch of the proposed method is physically implementable and when used with the elastic demand, wind power generation up to 50% can be accommodated. They showed that the most efficient way to implement the existing infrastructure is to enable current available SCADA with a multi-directional information exchange between the control center and the distributed decision maker, use this information interactively to manage inter-temporal constraints by distribution decision makers to create their supply and demand functions, and finally have system operator clear the supply and the demand functions by running today's SCED with its special constraints. Utilizing DR in wind penetrated networks in order to mitigate the randomized behavior of the RERs has been investigated in many other papers [34,35].

Strengths and weaknesses of the recently announced DRPs in [24] have been scrutinized in many papers. Real time pricing, as one of the most profitable DRPs, is investigated in [36]. In this paper, it is supposed that ISO has the authority to pile up bids and offers from Generation Companies (GENCOs), Transmission Companies (TRANSCOs), Load Serving Entities (LSEs), and Curtailment Service Providers (CSPs) and then by solving a SCUC considering hourly DR with inter-temporal load characteristics, both electricity price and scheduling supply and demand are optimally determined. The proposed method implements the SCUC in order to maximize the social welfare by adding realization DR constraints (i.e. minimum up/down time limits, load pickup/drop rates, minimum hourly curtailment, and maximum daily curtailment) in the optimization problem. The results show that (1) peak load reduction would mitigate price spikes and enhance economical dispatch (2) changes in hourly demand profile can cause reduction in the average system Local Marginal Price (LMP), (3) DR application in some buses in the grid could provide benefits to the entire power system and all market participants, (4) SCUC is preferred instead of SCED because SCUC would enhance the flexibility and the efficiency of market operations, (5) higher DR means not only more flat demand curve but also lower fuel consumption and less carbon footprint in power system. A novel approach for real time DR model along with electricity price uncertainty is proposed in [37]. Price uncertainty is modeled through robust optimization using duality properties and exact linear equivalences [38]. Meanwhile, the presented model is expressed in linear programming algorithm in order to be easily implementable in EMSs.

The concept of price elasticity of demand is widely investigated in [4,39–41]. Price elasticity of demand can be defined as the ratio of the relative change in demand to the relative change in price [4]. Interruptible/curtailable load as one of the most beneficial DRPs based on price elasticity of demand has been investigated in [40]. Price elasticity in [40] is bisected in self-elasticity and cross-elasticity. Self-elasticity represents the characteristics of such loads which are not able to move from one period to another (e.g. illuminating loads), and they always have negative elasticity. Cross-elasticity, however, is related to those loads, which can be transferred from the peak period to the off-peak, or low periods (process loads). In order to model single period elastic loads, the procedure proposed in [40,41] has to be implemented. Authors showed that the following equation declares that how much should be the customer's consumption to achieve maximum benefit in a 24 h interval while participating in I/C and CAP programs.

$$d(i) = d_0(i).\left\{1 + E(i,i).\frac{[\rho(i)-\rho_0(i)+A(i)+pen(i)]}{\rho 0(i)} + \sum_{j=1}^{24} E(i,j).\frac{[\rho(j)-\rho_0(j)+A(j)+pen(j)]}{\rho_0(j)}\right\} \tag{1}$$

where $d(i)$ and $d_0(i)$ are the optimal curtailed load and the initial load respectively. ρ_0 (i) is the initial price and $\rho(i)$ is the secondary price, which has to be determined during optimization solving. $E(i, i)$ and $E(i, j)$ are the self-elasticity and the cross-elasticity of demand in different hours. Depending on incentive based or penalty based DRPs, $A(i)$ and $pen(i)$ can be accommodated in the above formula. The achieved formula has been employed in many recent papers to model the responsiveness of the demand. Aggregating all four possible demand vs. price formulations (i.e. linear, logarithmic, potential, exponential) by weighting coefficients, based on optimal curtailed load, caused a comprehensive model of DR proposed in [39]. Moreover, dynamic price elasticity is investigated instead of fixed price elasticity. In [32] a Demand Response Unit Commitment (DRUC) is solved considering non-penalized DRPs (i.e. DLC, EDRP) using the optimal curtailed load as a proportion of the initial load. Comparing many versatile case studies showed that DR as a virtual power plant can significantly influence on both fuel cost and emission cost reduction. In [45] curtailed demand in DRPs is treated as virtual generation unit. In this paper, it is assumed that the difference between initial and curtailed demand would have a marginal cost and a cost function respectively. By adding realization constraints such as ramping rates, minimum up/down time, and the constraints regarding the customers' information, the virtual generation would be more applicable.

8.1. Demand response and integrating RESs

As stated in the previous sections, integrating renewable resources into the grid in large scales is along with some restrictions, which are scrutinized in this section. Moreover, to reconcile between conventional generating units and the renewable power resources multi-operation, special DRPs are also investigated.

RESs are intermittent resources and integrating them into the grid means dealing with many uncertainties. The uncertainties with each time intervals and the proper services to deal with each time interval uncertainty are illustrated in Table 1.

Prior to announce the required DRPs in order to counteract the effects of uncertainties, introducing general additional required infrastructures for a RES integrated system seems crucial.

To prepare the power system for integrating RESs, the reliability of the power system has to be increased through the following requirements:

increase the need for regulation, spinning reserve, and load following resources;
resulting in steeper system ramping requirements;
increase the frequency and magnitude of over-generation events;
resulting in less efficient dispatch of conventional resources.

As the first alternative says, power system operator requires many different ancillary services in order to maintain the balance between demand and supply. The suitable services to deal with the different uncertainties are as follows:

- Spinning reserve: Spinning reserve is the portion of unloaded capacity from units already connected or synchronized to the grid and that can deliver their energy in 10 min and run for at least two hours.

Table 1
Uncertainties in different time intervals.

Variations within Seconds	
Need immediate response:	Frequency Response
Variations within Minutes	
intra 5-minute volatility & 5 -minute forecast error:	Regulation
Variations whithin the hour	
Intra hour volatility & Hour ahead forecast error:	Load following/Ramping
Variations whithin the day	
Day ahead Forecast error:	Additional resource commitment

- Non-spinning (or supplemental) reserve: Non-spinning (or supplemental) reserve is the extra generating capacity that is not currently connected or synchronized to the grid but that can be brought online and ramp up to a specified load within ten minutes.
- Regulation up and regulation down: Regulation energy is used to control system frequency that can vary as generators access the system and must be maintained very narrowly around 60 Hz. Units and system resources providing regulation are certified by the ISO and must respond to 'automatic generation control' (AGC) signals to increase or decrease their operating levels depending upon the service being provided, regulation up or regulation down.

The second requirement addresses the rapid changes in the generation of the renewables. The integration of such resources requires defining proper ramp rates and load following services:

- Maximum continuous ramping: Maximum continuous ramping is the megawatt amount by which the net load (load minus wind and solar) is expected to change in either an upward or a downward direction continuously in a given month.
- Load following: load following is the ramping capability of a resource to match the maximum megawatts by which the net load is expected to change in either an upward or a downward direction in a given hour in a given month.

Generally, the required DRPs as ancillary services, as stated in Table 1, are:

- Frequency response: immediate response (up to 20 seconds) in response to contingencies;
- Regulation: manage uncertainty in 5–10 min ahead forecasts;
- Following/ramping: manage remaining intra-hour uncertainty;
- Additional resource commitment: manage deviations between day-ahead and hour-ahead schedules.

These programs are briefly tabulated in Fig. 7 [48].

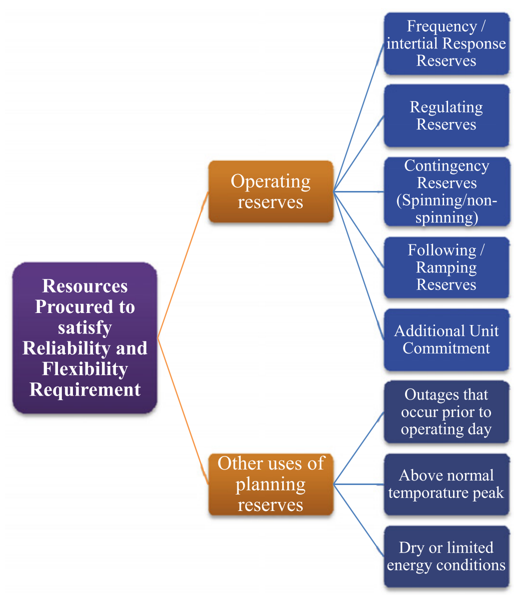

Fig. 7. Resources needed to satisfy grid reliability and flexibility requirements.

9. DR status Quo

In this section, three main implementations of DRPs, in USA, Europe, and China, are discussed in many aspects.

9.1. USA

The 2010 FERC Survey [24] results indicate that the majority of customers enrolled in a direct load control program are in programs offered by their Investor-Owned Utilities (IOU), reflecting the larger number of customers in IOUs. After IOUs, cooperatives have the most customers enrolled in direct load control programs.

It is noteworthy that over 10 percent of customers in MRO and FRCC regions participate in direct load control programs. In FRCC, Florida Power and Light's On Call direct load control program is the largest such program nationally, with over 800,000 customers enrolled. Besides direct load control programs, participation in interruptible/curtailable programs showed an upward trend from 248 in 2008 to 265 in 2010 where more than 85 percent of the reporting entities are IOUs and Cooperatives [11]. Next comes TOU programs, contributing to an overall decline from 241 entities in the 2008 to 169 entities in the 2010 while a reported 1.1 million US residential customers are enrolled in time-of-use rates in the US [24].

Despite time-of-use offerings by dozens of entities across the US, and particularly in MRO, most residential customers with time-of-use rates are in WECC. Wholesale market participants also had the largest increase in potential peak reductions: from 12,656 MW in the 2008 to 22,884 MW in the 2010 [24]. Much of the increase in the wholesale class is due to the growth of demand response in RTOs, from a reported 9060 MW in 2008 to 20,533 MW in 2010. Since 2007, ISO New England and PJM Interconnection have commenced long-term forward capacity markets that have attracted significant amounts of demand response.

Commercial and industrial customers' potential load reduction increased by 23 percent from 2008 to 2010. The top four demand response programs, emergency response, interruptible load, direct load control, and load as capacity resource account for 79 percent of the total US peak load reduction potential. Except for direct load control, these programs predominantly enroll wholesale, commercial, and industrial customers that bring high per participant peak load reductions. Direct load control programs are typically targeted to residential and small nonresidential customers; the controllable technologies are relatively homogeneous across these customers. Radio or other communication signals sent by the program sponsor are necessary for effective control of the large numbers of small loads [11].

9.2. Europe

In this subsection DR experiences in three European countries namely, Norway, Italy, and Spain are reported. In Norway specific programs have been undertaken with the objectives of postponing expansion of grid capacity: 10% reduction in peak demand in the Oslo area; increasing knowledge of customer behavior; and developing a motivation model for DSM [31]. Pilot studies show that using this DR program the peak load for commercial end-users was reduced by 4.5 MW and the energy saving was around 15%. In Italy, Interruptible Programs, applied to very large industries, only represent 6.5% of peak power and Load Shedding Programs initiate automatic load shedding in emergencies [42]. Load Shedding Programs are divided into real time programs (without notice) and 15 min notice programs. The size ranges from 1200 MW for real time programs to 1750 MW for notice programs. Participants in these programs have to install and maintain Load Shedding Peripheral Units and will be compensated according to a non-market price defined in regulation. The size of curtailable power is of 10 MW for programs without notice and 3 MW for programs with notice. Currently, DR programs in Spain focus mainly on industry, as most European utilities include Direct Load Control programs as part of their DSM strategies, with fixed compensations attributed to small numbers of large industrial end-users. Interruptible Programs for large industries are very frequent, although the mechanisms for compensating industries vary significantly. The extent to which such system-led programs can be labeled as authentic DR initiatives is debatable. In the future, however, large numbers of end-users, including commercial customers and households could be involved in DR programs with compensations consisting of prices and deliberate shifts in electricity demand in correspondence with peak loads [43].

9.3. China

The DRPs in China have been flourished mainly through TOU and interruptible load pricing and deployment of energy storage devices [30]. Based on the mentioned DSM, just in Beijing, significant load factor enhancement is obtained, at about 81 percent in 1997. It is worth noting that the load factor would have decreased to 76.59 percent if no DSM had been used [44]. The following actions have been taken up to 2003.

The difference between the on peak and off-peak electricity price was risen. By the end of 2003, more than 77,431 consumers, participated in TOU programs, represent 61.69% of the total consumption.

Interruptible load contracts have been signed with major industrial loads such as Yanshan Petrochemical Corporation and Shougang Group. The result was 100 MW shifted peak load each year.

Loads were controlled at Electric Load Management Center (ELMC). Wireless communication infrastructure connects more than 5000 consumers. In 2003, 1600 locations with 2800 MW of load were connected, and approximately 500 MW could be directly controlled.

10. Conclusion

In this DR comprehensive review the latest modifications in DR definition and classifications are scrutinized. Moreover, benefits and related expenditures are categorized extensively. A literature review of the very recently published papers about DRPs is presented. Eventually, successful DR experiences throughout the world are assessed.

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